6 Options and Scenario Analysis

6.1 Summary Findings of the Analysis

The San Diego region faces a highly uncertain energy future. There is uncertainty regarding the demand forecast, generation supply, fuel prices for generation, and the level of energy efficiency and DG-renewables that will help avoid supply/demand imbalances.

With the current economic conditions in the energy market, it is not certain when and if new generation will be built. The region also would be severely impacted if one of the two major transmission lines serving the county were not able to import power.

The implications are that a balanced portfolio of generation, transmission and energy efficiency-demand reduction and DG-renewables are needed to help limit these risks.

The balanced portfolio would be achieved by:

- Ensuring that new generating plants are built when needed
- Extending the life of marginal generation units that are planned to be terminated in the next few years if no new generation is built
- Considering expanding new transmission capability to the extent required to achieve a balanced portfolio
- Aggressively pursuing energy efficiency, DG and renewables.

The scenario analysis shows that with a strong commitment to energy efficiency and DG-renewables, the region can avoid building from one to two new generating plants over the 2002–2030 planning period. It is estimated that from two to three generation plants of 500 MW will be needed during this period, assuming other resources are also provided. Some of this new capacity can be off set with repowering of existing generating units.

Major Findings of Scenario Analysis

- **Current market and regulatory conditions do not assure adequate and economical supply. The region needs to take action to insure that adequate new energy supplies are available.**
- **It is possible to avoid imbalances by investing heavily in energy efficiency and DG-renewables.**
- **The region needs a balanced portfolio of resources consisting of new generation, transmission, energy efficiency and DG-renewables.**
- **The region needs to carefully monitor supply and demand over the next 5 years, because imbalances or shortages can occur if new generation and other supplies are not available.**
- **The region needs to diversify fuel supply and reduce the dependency on natural gas fired electric generation.**
- **An unexpected outage of one of the two major transmission paths serving San Diego County would create a significant imbalance and result in a substantial cost increase.**

A key outcome of the region's energy strategy should be to seek secure supply, develop flexible options and achieve price stability.

The most critical time period that needs to be managed is the next 5 years—between 2002 and 2006. The region needs to carefully monitor the supply/demand balance during this period and ensure that needed generation and other resources occur as planned.

Specific recommendations by time period are the following:

6.1.1 Short Term (2002–2006)

1. The region may be facing significant retirements of older economically less attractive generating plants such as Cabrillo Units 1–3. There will be a net capacity reduction in the County if no new generating units are built or are repowered. These units could be either extended or repowered to help contribute to the new generation supply that is needed during this period.[1]

[1] SDG&E points out that South Bay and Cabrillo Unts are must run and cannot be shut down withou replacements.

2. It is not clear that any of the identified generating projects will be built during this period although one to two new generating plants are needed between now and 2010. The region needs to address this issue and take action to insure that adequate new generating supply is available.

3. There is a shortage of transmission capacity serving San Diego County. This affects the County's ability to import contracted power supply and affects regional reliability.

4. The County is now served by two major power plants for South Bay and Cabrillo, which are older units and will be retired by 2009. Some Cabrillo units will continue to operate beyond this period. As new generation or transmission is added to the resource base, the competitiveness of these units will come into question. However, these units are valuable candidates for life extension and a valuable backup for reliability support.

5. Significant investments in energy efficiency and DG-renewables could help alleviate a near term tight supply/demand balance. This should be a priority.

6. The region is currently relying on the market to fulfill its generating needs, yet this market has little cash flow and liquidity at the moment and no new significant plants in the County are being built.

7. The region is not an attractive location for new plant development. The region needs to balance its need for new generation in the County with that of having a link to substantial new generation that will be built in neighboring areas including Arizona and North Baja. Currently there are transmission limitations to these markets.

8. A region-wide dynamic load flow and optimization study is needed of County transmission and distribution (T&D) in order to identify areas of improvement in capacity and reliability. T&D planning should be conducted in a more integrated manner before significant new resource investment occurs.

9. Under a lower growth scenario, a combination of new in-County generation additions, power imports and energy efficiency and DG-renewables, the County can avoid significant imbalances in the next 5 years.

6.1.2 Medium Term (2006–2010)

1. The region will need from one-to-two new base load plants (or an existing unit repowered or replaced) of 500 MWs each during this period, depending on what resource development occurs in the 2002–2006 time period. If new transmission is built by 2006 there should be no need for additional transmission until the post 2015–2020 period, except for transmission linking San Diego County to North Baja.

2. If demand growth is higher than expected, and if fewer power plants and less transmission capacity are developed than needed, significant imbalances could occur. On the other hand, if the plants are built and the levels of energy efficiency and DG-renewables occur as expected, the region should meet its load obligations.

3. A new transmission line to the North would help the region improve reliability and price stability for power, and create a market for capacity that is developed in the County. This would also limit potential stranded cost for capacity in the County. In addition, the region would have access to power from the North and East, with added transmission interconnection to Arizona from Orange County.

4. By this period Cabrillo Units 1–4 and potentially South Bay will have been retired. However, if no new generation or transmission is developed, the operation of these units may have to be extended as a stop-gap measure to assure adequate coverage of load and to meet minimum reliability requirements.

5. An outage of either the largest unit or a major transmission supply line could create significant supply shortages and be very costly to the region.

6.1.3 Long Term (2010 and Beyond)

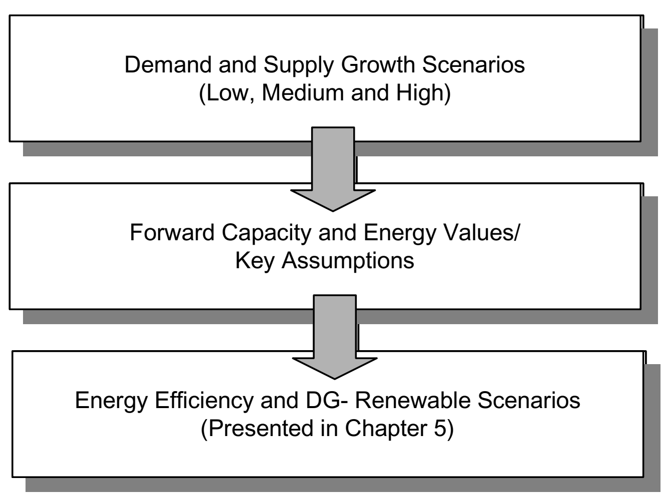
1. A substantial amount of new generation will be built in Arizona and North Baja by this time, providing less expensive sources of power. The region should monitor this situation and see how economical this power supply is—provided the necessary transmission access exists.
2. Significant new generating capacity will be needed in the post 2020 time period. It is expected that new power plant projects will be considered and developed, or that additional import capability will exist.
3. Additional transmission to the North and East will be needed to take advantage of the generation that is being developed in these adjacent regions. Also, if natural gas prices are high due to the higher demand for gas from new power plants, Arizona represents a possible hedge against higher prices with the possibility of additional coal plants being built.
4. The state and region should be experiencing a significant amount of DG and renewable penetration during this period.
5. There is the chance that significant new interstate transmission access will occur linking Southern California to the Eastern part of the United States. As natural gas prices increase, and as the cost of new coal plants is reduced, more coal plants will be developed in the post 2020 period and could be a source of lower cost and stable electricity.

6.2 Background

This section presents the results of the scenario analysis and implications for alternative energy supply and demand conditions. In addition, key assumptions for alternative wholesale electric supply price conditions are also presented. Implications from alternative energy efficiency, DG and renewable supply levels and the potential implications of forced outages or import supply interruptions are also presented. The capacity supply impacts of additional transmission are also investigated. This analysis does not include a cost and reliability assessment of transmission options, although the value of transmission was evaluated in terms of contributing to the region's peak load requirements.

A forward electric wholesale price analysis was completed by analyzing generation expansion in the WECC during the period 2002–2030, using New Energy's MarketPower. This latter analysis takes into account different assumptions on gas prices, assumed plants that will be built in the WECC, transmission constraints that are likely to exist in the region, and the premium price for power plants built in the state and region. A higher discount rate was assumed for power plants being built in California due to the high political and market risks that exist for new plant development.

Figure 6-1. Scenarios and Key Assumptions



6.3 The Scenarios

A scenario approach was used to evaluate each electric supply and demand situation for the 2002–2030 period. Figure 6-1 illustrates the scenarios and inputs used in evaluating resource options. Appendix D presents data on the planned generation plants in operation during this period and the peak demand forecast.

The supply and demand growth scenarios were used to describe possible alternative future energy resource conditions, recognizing a broad portfolio of supply and demand options. These are described below. In addition, the possible conditions that would affect generation expansion in San Diego County and the WECC were modeled using the MarketPower Model. This led to a series of forward prices that define the avoided energy and capacity prices to screen demand side program options. Consistent with the growth scenarios, estimates of demand side and DG-Renewable resource options were evaluated using the avoided costs. This is presented in Chapter 5 and the estimates appear in the scenarios below. This chapter focuses on the supply/demand growth scenarios and the forward demand and energy price estimates.

The key assumptions for the energy supply and demand growth scenarios are presented in Table 6-1. Key features of the scenarios are the following:

- *Scenario 1 – The Low Growth and Optimistic Scenario:* The expected optimistic development of in-County generation and a low deployment of energy efficiency, on-site distributed generation (DG) and renewable resources are assumed. Because of low load growth and relatively stable prices, there is a minimum level of demand management and DG-renewables developed.
- *Scenario 2 – The Base Case/Medium Demand Growth and Optimistic Supply Scenario:* Expected power plant development occurs as planned from earlier announced projects even though many of these projects are indefinitely on hold. A moderate deployment of energy efficiency, demand reduction, DG and renewable resources occurs. There is also investment in advanced meters and institution of pricing initiatives. Added incentives for distributed generation and local generation investments occur because locational marginal pricing (LMP) is applied in Southern California. The effects of new transmission on capacity supply are also investigated. The impact of a forced outage on the largest generating unit and transmission supply artery is also evaluated.
- *Scenario 3 – High Demand Growth and Worst Case Development Scenario:* Aggressive deployment of on-site distributed generation and renewable resources. This scenario represents an aggressive effort to balance network capacity, generation supply and demand options. This scenario also incorporates the SDG&E 1-in-10 year planning condition.

Assumptions for the Base Case Medium Demand Growth scenario include the following:

- SONGS receives a license extension in the late 2002–2010 time period and continues operation through 2030.
- The Cabrillo power plant is repowered or replaced after 2010.
- The Otay Mesa plant is built and made operational by December 31, 2004. (Note: this is not a certainty).
- The South Bay goes off line by the end of 2010.
- Cabrillo Unit 1 is retired in 2004, Unit 2 in 2006 and Unit 3 in 2008 due to an assumption that steam units are retired after 50 years of operation.
- There are 213 MWs of gas turbines (GTs).
- Qualified Facilities or “QFs” are 175 MWs of generating capacity.
- Peaker additions provide 213 MWs of generation.
- Two additional power plants with a nominal output of 500 MWs are built between 2010 and 2020. This could be any one of a number of projects currently being considered (e.g., Sempra Palomar in Escondido, ENPEX or some other unit).
- The state of California implements a policy of achieving a 15-percent reserve margin over the CA-ISO peak and each regional ISO utility is responsible for achieving their proportion of this peak.

- The state of California and the region lag slightly behind in meeting the required renewable energy portfolio standard imposed by AB 57 that has a goal of ensuring that at least an additional 1 percent per year of the electricity sold by the electrical corporation is generated from renewable energy resources.
- Defined proportions of energy efficiency and DG-renewables are achieved based on the COMPASS analysis presented in Chapter 5 and estimates that appear in Table 5-10.

Table 6-1. Description of Demand and Supply Scenarios

Key Drivers/Attributes	Low Demand Growth and Optimistic Supply	Base Case: Medium Demand Growth and Optimistic	High Demand Growth and Worse Case Supply
Peak Load Growth Rate			
Gas	1.2%	1.4%	1.6%
Electric*	1.8%	2.0%	2.5%
Energy Growth Rate			
Gas	1.0%	1.2%	1.4%
Electric	2.0%	2.3%	2.5%
Metering Situation	200 kW and above have interval metering/real-time pricing not used until 2005	200 kW and above have time-of-use meters and limited demand response programs	200 kW and above have interval meters In addition, 75% of customers less than 200 kW have time-of-use meter
Transmission Pricing	No LMP pricing	LMP pricing	LMP pricing
Wholesale Power Prices	Low/stable prices	Medium/Mod. Volatile	Highly Volatile
California Energy Market Situation	No choice for next 3 years	Limited choice 4–5 years	Competitive market post 5 years
Generation Supply	Optimistic supply. Identified projects are built as scheduled. Includes Otay Mesa by 2004, Cabrillo units start retiring, and South Bay is replaced.	Optimistic supply. Identified projects are built as scheduled. Includes Otay Mesa by 2004, Cabrillo units start retiring, and South Bay is replaced. Simultaneous import capability increases to 3200 MW.	Pessimistic supply or worse case supply. No new generation is developed over the 30-year period. No new transmission except small upgrades and additions. Simultaneous import capability stays at 2500 MW.
Transmission Constraints	No Rainbow Valley	Rainbow Valley or alternative is built by 2009 Capacity Reservation Market in place	Rainbow Valley or alternative is built in 2010 Capacity Reservation Market in place
Energy Efficiency/ Demand Response	Lower investment level and impacts	Moderate investment level and impacts	High investment level and impacts
Distributed Resources/ Renewables	Low priority, little support	Medium priority, moderate support	High priority, high contribution
DSM Evaluation	Avoided cost $99–212	Avoided cost: $99–253	Avoided cost: $142–253

Appendix D presents the list of assumed generation plant availability for the 2002–2030 study period.

Defined proportions of energy efficiency, DG, load management and renewables are presented based on meeting certain cost effectiveness criteria. A range of low, medium and high cost-effective measures is included. In addition, to the base case or medium scenario, two demand growth sensitivity analyses were completed.

6.4 The Resource Balance: Supply and Demand Balance with Energy Efficiency and DG-Renewable Resource Options

Table 6-2 presents a summary of the supply/demand growth scenario using SAIC's base forecast for the low, medium and high demand growth scenarios. The low and medium scenarios are based on SAIC's application of the 50-50 SDG&E and CEC forecasted growth rates from 2002–2010. Then SAIC extrapolated the growth rates to 2030. The high growth rate is driven by the SDG&E 1-in-10 forecast growth rate that appeared in the Valley Rainbow filing of July 2002. The "SD Peak and Reserves" includes a 15-percent reserve margin that the state is working to achieve. The forecast peak demand includes losses and it is also applied to a small part of Orange County—this load can vary as much as 4 to 6 percent in any 1 year. This load was included after discussions with SDG&E, because much of the generation expansion and import decisions are based on a system wide planning requirement.

For the low and medium growth scenarios, the optimistic generation supply assumptions were used. The generation and import data consist of in-basin generation that includes existing steam units, namely Cabrillo Units 1 to 5 and South Bay Units 1 to 4. Except for Cabrillo Units 4 and 5, the remaining Cabrillo units are expected to be terminated by 2007, because they will have been in operation for 50 years and are relatively less efficient in terms of heat rates. South Bay is expected to be retired around 2006–7 and replaced by 2009. A replacement to South Bay is assumed as part of new generation additions in the County. GTs are assumed to total 213 MW for the planning period. QFs and Cogeneration that SDG&E recognizes is estimated to be 175 MW. Peakers are estimated to be 336 MW. The estimates of in-County generation appear in Appendix D. These units were reviewed and corroborated with SDG&E. The new generation was announced before the current down-turn in the power development business that has been occurring over the past 18 months.

The imports component or the generation and import values shown in Table 6-2, assume the Valley Rainbow T&D project is completed which increases the simultaneous import capability to 3,200 MW, and provides by 2006 for an additional 720 MW of export capability that does not currently exist. However, there is uncertainty on whether or not this line will be built. The analysis shows no deficits over the planning period. This is because a relatively lower growth rate is assumed (1.8 and 2.0% versus the 1-in-10 growth rate of more than 2.5%). In addition, new generating units are assumed as well as a large contribution from energy efficiency and DG-renewable.

The estimated demand growth rates for the low and the medium demand growth scenario are a bit lower than the SDG&E 1-in-10 growth rate. In sensitivity analysis SAIC uses the SDG&E 1-in-10 growth rate used for the Valley Rainbow filing by SDG&E and reserves of 15 percent were added. The sensitivity analysis shows that the region either has sufficient supply to meet near term peak load requirements or it will face a deficit as early as the 2004–2006 time period—if no new resources are built. The new resources could include such possibilities as Otay Mesa, repowering existing facilities, new transmission or if the estimated level of DSM and renewables is realized. If this does not occur, then the region could face some imbalance and higher prices.

The high growth and pessimistic supply scenario assumes no new generation is added nor any new transmission capability—leaving the region to a simultaneous import level of 2,500 MW. This scenario shows near term imbalances, which increase, to large levels in the final 10-year decade of the planning study.

Table 6-3 shows a summary of the supply/demand balance under each of the scenarios assuming a worse case supply, energy efficiency and DG-renewable supply condition. The low and medium growth rates are based on 1.8- and 2.0-percent growth. The higher growth rate is based on a 2.5-percent growth rate—which parallels the SDG&E 1-in-10 growth rate. These scenarios also assume a worse case supply situation with no new supply from generation or other transmission. The scenarios show shortages or imbalances occurring very early—as early as 2006, and possibly as early as 2004.

Table 6-2. Supply/Demand Balance Assuming Optimistic Energy Efficiency and DG-Renewables, 2006-2030 (MW)

	2006	2010	2020	2030
Low Demand				
SD Peak + Reserves	5037	5429	6489	7757
Generation +Imports	5171	5562	5562	5562
Adjustments*	467	860	1742	2741
Net	601	993	815	546
Medium Demand				
SD Peak + Reserves	5037	5429	6618	8067
Generation +Imports	5860	5562	5562	5562
Adjustments*	661	1387	2523	3651
Net	1484	1520	1467	1146
High Demand				
SD Peak + Reserves	5037	5932	7593	9720
Generation +Imports	5171	5562	5562	5562
Adjustments*	1032	1823	3165	4396
Net	1166	1453	1134	238

* Adjustments mean reduced peak demand from energy efficiency, demand reduction programs, DG-renewables.

Table 6-3. Supply/Demand Balance Assuming Worse Case Supply, Energy Efficiency, and DG-Renewables, 2006-2030 (MW)

	2006	2010	2020	2030
Low				
SD Peak + Reserves	5037	5429	6489	7757
Generation +Imports	3961	3889	3889	3889
Adjustments*	233	430	870	1370
Net	-843	-1110	-1730	-2498
Medium				
SD Peak + Reserves	5037	5429	6618	8067
Generation +Imports	3961	3852	3852	3852
Adjustments*	336	684	1263	1825
Net	-740	-893	-1503	-2390
High				
SD Peak + Reserves	5037	5932	7593	9720
Generation +Imports	4859	4650	3852	3852
Adjustments*	516	912	1573	2199
Net	129	-1168	-2168	-3669

* Adjustments mean reduced peak demand from energy efficiency, demand reduction programs, DG-renewables.

The result of the scenario analysis shows that the region:

- Needs to be more proactive in securing future supply capacity—whether from generation or transmission
- The region needs to carefully monitor the retirements of existing plants and the scheduling of more efficient replacement plants in the region
- The region has import obligations that exceed import capability which means that some of these imports that are take or pay obligations will not be able to reach the local market
- Unplanned outages of SONGS or SWPL which are the two main paths of electric imports into the County could create severe shortages unless additional in basin supply or new transmission is added
- SDG&E is correct in its Valley Rainbow filing that it is difficult to plan on any new generation being built in San Diego County under the current conditions of the electric supply industry and the fact that San Diego is not the most attractive location to site and build new power plants. For this reason, the region needs to be much more proactive in securing new generation and carefully managing the interplay of new generation development, older generation retirements, the siting and need for new transmission and defining the role for energy efficiency, demand reduction, and DG-renewable programs.
- Energy efficiency, demand reduction and DG-renewables should be aggressively pursued because they are good insurance to manage the risks of higher than expected demand growth and excessive dependency on natural gas fired generation or imports. Programs that lower coincident peak demand should be a priority.

Table 6-4 presents a more detailed presentation of the Base Case/Medium scenario. A key finding from the evaluation of this scenario is that it provides a flexible resource base where a number of variable outcomes can occur that leave sufficient reserves to meet demand. The following observations can be made:

- If all resources occur as expected, including two new base load plants and a possible repowering project, no new generation would be needed over the balance of the planning period.
- If one major project does not occur—whether it is one base load plant or if the Valley Rainbow project does not occur, there would still be sufficient net reserves available to positively balance supply and demand. However, reliability could still be jeopardized.
- The region could withstand a shortfall of energy efficiency and DG-renewables if only one half of the resources were provided—there would still be sufficient reserves.
- These findings already include an assumed 15 percent surplus investment in generating capability to stabilize prices and provide for minimum levels of reliability.
- However, when a major outage occurs from the loss of the largest generation unit in the region or when a forecast variance of 10 percent occurs reserves drop to approximately 700 MW over the critical 2006–2010 time period.

Table 6-4. Base Case Moderate Demand Growth and Optimistic Supply, 2002-2030 (MW)

Year	2002	2006	2010	2020	2030
Forecast (Note 1)	3741	4380	4721	5755	7015
15% reserves (Note 2)	561	657	708	863	1052
Total SD County Capacity Requirements	**4302**	**5037**	**5429**	**6618**	**8067**
In-County Generation (Existing)					
Conventional Steam Power Plants (Note 3)	1635	1426	628	628	628
GT Total	213	213	213	213	213
QF/Cogen	175	175	175	175	175
Peakers	336	336	336	336	336
Subtotal	2359	2150	1352	1352	1352
In-County Generation (New)					
Otay Mesa		510	510	510	510
South Bay 2 or Repowering of SB 1 Plant			500	500	500
New Peakers	0	0	0	0	0
New Unknown (Repower or New Plants)				0	0
Subtotal	0	510	1010	1010	1010
Total In-County Generation	**2359**	**2660**	**2362**	**2362**	**2362**
In-County Generation Percent	**55%**	**53%**	**44%**	**36%**	**29%**
Surplus/Deficit Before Transmission	**-1943**	**-2377**	**-3067**	**-4256**	**-5705**
Import Capability (Note 4)	2500	3200	3200	3200	3200
Net Balance/Imbalance (Note 5)	**557**	**823**	**133**	**-1056**	**-2505**
Alternatives					
Demand Reduction (Note 6)	40	145	290	553	811
DG- Non-Renewable (Note 7)	150	360	650	1200	1600
DG- Renewable/ San Diego County (Note 7)	25.1	156	447	770	1240
Total Adjustments	215	661	1387	2523	3651
Net Surplus/Deficit (Note 8)	**772**	**1484**	**1520**	**1467**	**1146**
Encina Unit 5 Outage (-329 MW)	443	1155	1191	1138	817
Forecast Variance of 10%	69	717	719	562	115

Note 1: Annual peak load requirement including transmission losses. Excludes impacts of incremental DSM programs.

Note 2. Assumes realization of desired 15% reserve margin for price stability and reliability.

Note 3: Existing steam generating plants and units in operation as shown in Table D-2 in Appendix D.

Note 4: Simultaneous import capability is the maximum amount of power that can be imported at the same time. This may vary form actual transmission capacity due to export and other load balancing requirements.

Note 5: Net imbalance is the net surplus or deficit of resources to meet peak load and reserves before demand response programs and DG being considered.

Note 6. Impacts of demand response, DG and renewables based on the COMPASS analyses

Note 7: Estimated DG resource impacts from Table 5-10.

Note 8. Net surplus or deficit in known capacity for the stated time period.

Table 6-5 shows a more severe supply situation. This scenario is a “worst case” situation that includes the following:

- No Otay Mesa, and no repowering of South Bay and no new units such as Palomar are built.
- Cabrillo Units 1,2, and 3,are retired.
- South Bay 1 is retired by 2009.
- Only about one-half of the potential demand reduction and DG-renewables is produced.

Table 6-5. High Demand Growth and Worse Case Supply Scenario

Year	2002	2006	2010	2020	2030
Forecast (Note 1)	3741	4380	5158	6603	8452
15% reserves (Note 2)	561	657	774	990	1268
Total SD County Capacity Requirements	**4302**	**5037**	**5932**	**7593**	**9720**
In-County Generation (Existing)					
Conventional Steam Power Plants (Note 3)	1635	1426	628	628	628
GT Total	213	213	213	213	213
QF/Cogen	175	175	175	175	175
Peakers	336	336	336	336	336
Subtotal	2359	2150	1352	1352	1352
In-County Generation (New)					
Otay Mesa	0	0	0	0	0
Repowering South Bay Power Plant	0	0	0	0	0
New Peakers	0	0	0	0	0
New Unknown (Repower or New Plants)	0	0	0	0	0
Subtotal	0	0	0	0	0
Total In-County Generation	**2359**	**2150**	**1352**	**1352**	**1352**
In-County Generation Percent	**55%**	**43%**	**23%**	**18%**	**14%**
Surplus/Deficit Before Transmission	**-1943**	**-2887**	**-4580**	**-6241**	**-8368**
Import Capability (Note 4)	2500	2500	2500	2500	2500
Net Balance/Imbalance (Note 5)	**557**	**-387**	**-2080**	**-3741**	**-5868**
Alternatives					
Demand Reduction (Note 6)	40	97	184	373	556
DG- Non-Renewable (Note 7)	75	250	400	700	883
DG Renewables (Note 7)	25.1	169	328	500	760
Total Adjustments	140	516	912	1573	2199
Net Surplus/Deficit (Note 8)	**697**	**129**	**-1168**	**-2168**	**-3669**
Encina Unit 1 Outage (-329 MW)	368	-200	-1497	-2497	-3998
Ten Percent Peak Load Variance	-6	-638	-2013	-3158	-4843

Note 1: Annual peak load requirement including transmission losses. Excludes impacts of incremental DSM programs.

Note 2. Assumes realization of desired 15% reserve margin for price stability and reliability.

Note 3: Existing steam generating plants and units in operation as shown in Table D-2 in Appendix D.

Note 4: Simultaneous import capability is the maximum amount of power that can be imported at the same time. This may vary form actual transmission capacity due to export and other load balancing requirements.

Note 5: Net imbalance is the net surplus or deficit of resources to meet peak load and reserves before demand response programs and DG being considered.

Note 6. Impacts of demand response, DG and renewables based on the COMPASS analyses

Note 7: Estimated DG resource impacts from Table 5-10.

Note 8. Net surplus or deficit in known capacity for the stated time period.

This analysis shows that the region swings from a strong surplus in the Medium Case/Optimistic Supply analysis (Table 6-4) to a short-term and ongoing deficit that is extreme in later years. This condition is not practical and likely to occur—although the risks of such a situation should be known. It is expected that new generation will be built. Current import capability of 2,500 MW is assumed with no new transmission being added to the region. If for some unanticipated reason the entire transmission corridor through SONGS is interrupted, as actually occurred in February of this year, the import capability serving San Diego County would be reduced to approximately 1,200 MW. This would create a severe supply situation in the County if it occurred during a period of high demand. Adding a major new transmission path such as Valley Rainbow could provide an additional 700 MW of import capability in the near term, which would be very valuable in such a dire situation. Furthermore, there is only 720 MW of export capability from San Diego County northward to the rest of the state. With additional transmission capacity and two-way flow capability like Valley Rainbow or other transmission capacity, this could significantly increase the export capacity and create greater incentives for new generation developers to locate in the County. This would also help stabilize in-basin capacity values and help avoid the higher cost of LMP pricing.

The region is also faced with a very unique situation. The region has a regional power supply commitment that exceeds the simultaneous import capability. Current import requirements are:

Purchased power (take or pay) CDWR contracts		2,100 MW
Self serve or direct access imports		600 MW
SONGS imports		430 MW
Total Required Import Capability		3,130 MW
Maximum Import Capability Today		2,500 MW
	Deficit	(630 MW)

The imports of SONGS and direct access customers take precedence over CDWR contracts. This means that the region is paying for CDWR power that it cannot import and use. In addition, the cost that the region pays for the CDWR power is assessed to SDG&E and the region on an annualized basis. The region will not know what the fixed and variable cost allocations are until an order is issued by the commission regarding the allocated costs.

A final sensitivity analysis was completed for the high-growth, 1-in-10 planning conditions: the expected generation units were added; Valley Rainbow or other transmission is built (see Table 6-6); and, the expected energy efficiency and DG-renewables occur. The results are a positive net balance except for a small deficit in 2030. If an unscheduled outage occurs, the net surplus is impacted, which underscores the value of a diverse portfolio.

6.4.1 Caveats

There are a number of caveats that should be considered when reviewing the scenarios. They include the following:

1. This analysis does not model reliability issues for the transmission network and hence trade-offs of plant or transmission line development or location is not modeled or evaluated. This type of analysis is being completed as part of the Valley Rainbow proceeding.
2. Capacity values of the DG and renewables may be inflated because they do not take into account availability at peak. Sensitivity analyses were used to test the potential impacts of lower capacity availability.
3. Peak load requirements could be 10 to 12 percent higher (which one of the sensitivity analyses addresses) to accommodate abnormal summer peak weather and a higher than anticipated economic recovery. This is why the 15-percent reserve margins are planned for as shown in the table.
4. The load forecasts can vary significantly from one reporting period to another. This is why low-, medium-, and high demand growth forecasts were used.
5. The current mix of resources, including in-basin generation supply, demand-side options and transmission imports (at least in the aggregate) will vary in proportion as the market evolves and future investments must be taken into account.
6. A drop in new generation occurs in the 2020–2030 period because no new generation units have been proposed for that period. It is likely that new generation units will be proposed in the 2015–2020 time period as reserves start to decline.

Table 6-6. High Demand Growth and Optimistic Supply, 2002-2030 (MW)

Year	2002	2006	2010	2020	2030
Forecast (Note 1)	3741	4673	5158	6603	8452
15% reserves (Note 2)	561	701	774	990	1268
Total SD County Capacity Requirements	**4302**	**5374**	**5932**	**7593**	**9720**
In-County Generation (Existing)					
Conventional Steam Power Plants (Note 3)	1635	1426	628	628	628
GT Total	213	213	213	213	213
QF/Cogen	175	175	175	175	175
Peakers	336	336	336	336	336
Subtotal	2359	2150	1352	1352	1352
In-County Generation (New)					
Otay Mesa	0	510	510	510	510
Repowering South Bay Power Plant	0	0	500	500	500
New Peakers	0	0	0	500	500
New Unknown (Repower or New Plants)	0	0	0	0	0
Subtotal	0	510	1010	1510	1510
Total In-County Generation	**2359**	**2660**	**2362**	**2862**	**2862**
In-County Generation Percent	**55%**	**49%**	**40%**	**38%**	**29%**
Surplus/Deficit Before Transmission	**-1943**	**-2714**	**-3570**	**-4731**	**-6858**
Import Capability (Note 4)	2500	3200	3200	3200	3200
Net Balance/Imbalance (Note 5)	557	486	-370	-1531	-3658
Alternatives					
Demand Reduction (Note 6)	40	145	290	553	811
DG- Non-Renewable (Note 7)	150	360	650	1200	1600
DG Renewable (Note 7)	25.1	156	447	770	1240
Total Adjustments	215	661	1387	2523	3651
Net Surplus/Deficit (Note 8)	**772**	**1147**	**1017**	**992**	**-7**
Encina Unit 1 Outage (-329 MW)	443	818	688	663	-336
Ten Percent Variance in Forecast	69	351	173	2	-1181

6.5 Wholesale Electric Price Forecast

6.5.1 Methodology and General Assumptions

Forward prices were used to determine the capacity and energy values in the market over a 30-year period. The prices were estimated using New Energy's "Market Power" model. The model analyzed the need for and dispatch of plants for the entire WECC. A competitive market model was assumed for wholesale electric prices. The WECC market was modeled, because it drives the marginal cost for the last unit of power purchased. The marginal costs are influenced by the types of plants dispatched, fuel costs, capital costs, heat rates, financial risks, transmission constraints and other factors. The marginal costs are also used to evaluate the benefits of energy efficient, demand reduction and renewable technology measures.

California Department of Water and Resources (CDWR) contracts[2] are not viewed as reflecting true marginal cost—even through they are expected to have an influence on retail prices through 2010. CDWR contracts are not market based— as evidenced by the state renegotiating the contracts. The result for evaluating energy efficiency and demand response programs from a retail customer's perspective may underestimate the near term benefits to customers. However, these benefits are inflated due to the peculiar situation that exists when state representatives entered into contracts

[2] DWR continues to renegotiate these contracts. http://www.dwr.water.ca.gov/

during a very unique condition in the market. In effect, a more conservative analysis was applied in this assessment.

This report presents a forecast of wholesale electric forward prices for San Diego County and adjacent areas. The approach for preparing the forecast was to simulate the behavior of the market through the use of a general equilibrium model. General equilibrium models produce projections of energy prices through the dispatch of specific generating units or groups of generating units while producing an optimized expansion plan through time.

6.5.2 Long Run Marginal Cost (LRMC) of Electric Generating Capacity

The LRMC of generating capacity was determined based upon the lowest-cost capacity resource that may be utilized in a given year additional capacity is required. In general, this approach closely resembles the "Peaker Method" used in past Integrated Resource Planning (IRP)[3] studies.

The approach SAIC used to evaluate each region in the WECC (1) Was additional capacity required in that year; (2) If so, what is the lowest cost resource to serve that load. In the long run this resource was typically a simple-cycle combustion turbine. The cost of this generation alternative was determined as the capital recovery and fixed O&M costs associated with this equipment's operation. However, if existing mothballed generation were available at a lower cost that equipment would be evaluated as the marginal unit.

An additional note is required for the generic simple-cycle combustion turbine used for San Diego County. In general, a 300-MW simple-cycle combustion turbine based upon GE 7F equipment was used. These units are large and capture all economies of scale available for this technology. However, San Diego County is disadvantaged in that the number of suitable sites for generating units is limited. Therefore, an assumption was made that smaller simple-cycle combustion turbine would be installed and larger sites would be reserved for combined-cycle combustion turbines. The cost parameters for a smaller unit based upon GE LM6000 technology was used. These units would allow for the installation of units on sites of approximately 50 MW.

The marginal cost of energy was based upon the dispatch of the most expensive unit in the region or the costs of imports from other regions. These costs would include: (1) The cost of fuel; (2) Emissions allowances; and (3) Non-fuel O&M costs such as water, water treatment chemicals and incremental maintenance costs.

The following general assumptions were employed in this analysis:

1. The projections were in nominal (2002) dollars.
2. SAIC assumed that a competitive wholesale electric market would develop in the California and the WECC. This is comparable to California Energy Commission (CEC) modeling assumptions.

Inflation forecasts used were adopted from the CEC. This report provided inflation estimates in nominal dollars until 2012. For periods after 2012 estimates for the last year were interpolated to the end of the study period.

[3] Integrated resource planning was in vogue in the 1980's and 1990's as a method of trading off supply and demand resources based on the last increment of capacity and energy needed to meet load requirements. The last increment of resource was viewed as the marginal cost upon which all demand resources were evaluated. As the electric industry moved from a cost based to a market based industry, interest and relevance of IRP started to wane.

6.5.3 Other Assumptions

6.5.3.1 Market Areas

SAIC performed this analysis for the primary market areas of The Western Electricity Coordinating Council (WECC) (formerly the WSCC).[4] A map of the WECC can be found in Figure 6-2. The California/Southern Nevada/Baja, California was further differentiated to isolate San Diego County, Southern California and Baja California.

Figure 6-2. WECC Region

Source: NERC. Applies to WSCC region.

6.5.3.2 Existing Generation Stock

All plants in North Baja California and the WECC including priority plants where the ground was either broken or significant permits have been obtained (e.g., Otay Mesa Power Plant) were included in the analysis. Sensitivity analyses based on different gas supply prices (recognizing their higher prices in California) and transmission access with and without Valley Rainbow were added as options in the analysis. The Market Power model took these factors into account when scheduling and dispatching the plants, depending on the scenario.

The total current generation in the WECC is 164,000 MW. The Market Power model contains a database of all electric generating units in the various reliability councils. The source of this information is Resources Data International (RDI).

These databases contain the following information for each unit:

1. Technology
2. In-service date
3. Maximum capacity
4. Heat rate
5. De-ration factors (i.e., the performance erosion of a plant under different atmospheric and meteorological conditions)
6. Fuel type
7. Forced-outage rate
8. Scheduled outage requirements.

6.5.3.3 Fuel Prices

The primary fuel prices that establish the marginal cost (dispatch price) are natural gas, residual fuel oil and coal. Nuclear fuel and distillate oil are also used in the region but rarely, if ever, establish dispatch prices. Furthermore, hydroelectric units are also sub-marginal. Fuel prices were established as follows:

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4 The Western Electricity Coordinating Council (WECC) was created on April 18, 2002 by merger of WSCC, the Western Regional Transmission Association (WRTA), and the Southwest Regional Transmission Association (SWRTA). Source: http://www.wecc.biz/wscc_rta_merger.html

- *Natural Gas* – Natural gas prices at Henry Hub[5] were adopted from the CEC. Table 6-7 details these values.
- *Residual Oil* – Residual oil forecasts produced by RDI were used in this analysis. Plants in Southern California were limited to a maximum residual oil burn of 2 percent per year.
- *Nuclear Fuel* – Nuclear fuel will increase at the weighted average of all other inflation costs of the economy.
- *Coal* – Coal price forecasted were supplied by RDI. Existing major coal units were generally forecasted on a station basis for larger units. Smaller and generic units were forecasted based upon regional coal price estimates.

Table 6-7. Natural Gas Prices Delivered to Electric Generating Units ($/MCF)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
SoCal Gas/ San Diego	2.94	3.00	3.06	3.16	3.25	3.33	3.41	3.48	3.56	3.63	3.70

Source: CEC 2002–2012 Electricity Outlook Report, Appendix A-2

These projections are produced from a general equilibrium model of the western United States. An alternative gas price forecast was prepared based upon projections from the U.S. DOE-EIA. These prices were derived from projections in the Annual Energy Outlook (AEO 2002), which is the EIA's annual energy forecast based on a general equilibrium model of North America. The CEC natural gas price projections provided pricing points for all regions modeled in the WECC. The EIA forecast used basis differentials constructed from Gas Daily pricing points. All natural gas price forecasts conformed to the CEC inflation forecast.

6.5.3.4 Load Growth

Load growth projections for non-California entities were taken from Form 714 filings made with the Federal Energy regulatory Commission (FERC). These filings were California load forecasts, with the exception of San Diego Gas & Electric, and were taken from the CEC 2002–2012 Electricity Report. The specific details of the SDG&E forecast are discussed in the Electricity Forecast section.

6.5.3.5 New Generation

New generation was introduced in this analysis in two ways: 1) Specifically identified units and 2) priority generating units introduced by the model in the creation of the expansion plan. For the first 3 years we know what plants will be built. In future years, we know some units will be built and the model solves this assuming the lowest available cost technology to meet the load requirements for the forecast period. Often this is a combined cycle gas unit.

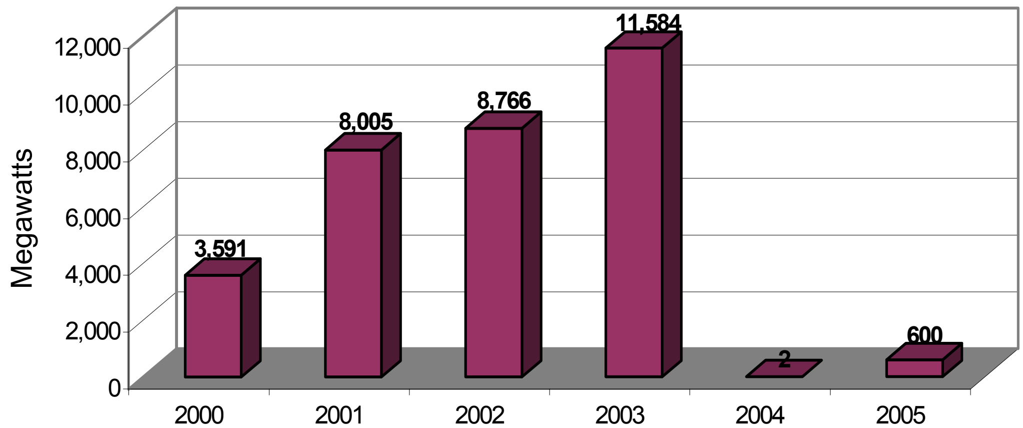
Figure 6-3 presents the estimated level of new generation that is anticipated in the WECC as of December 2001. Since then a substantial number of plants—approximately 50 percent have been indefinitely delayed or cancelled due to the financial market being concerned about capital and liquidity of developers.

The number of new megawatts of generating units was specifically identified was performed through extracts from the RDI NewGen database. After these reviews were performed, the projects deemed not likely to occur based on discussions with industry experts and specific developers were omitted.

Table 6-8 specifies the heat rates for combined-cycle and simple-cycle combustion turbines. The heat rate of the prototype technologies decreased over time in order to account for changes in technology.

[5] This is a natural gas trading and supply hub located on the Gulf Coast.

Figure 6-3. New Generating Projects in the WECC



Source: Market Power DataBase. Interviews with market developers.

Table 6-8. Projected Full Load Heat Rates by Technology Projected to Be Achieved in the Period 2002–2030 (Btu/kWh)

Year	Simple-Cycle Combustion Turbine	Combined-Cycle Combustion Turbine
2002–2008	10,487	6,566
2009–2013	10,427	6,435
2014–2018	10,070	6,306
2019–2030	9,871	6,180

Source: Ram MaDulgula of Sargent and Lundy. Theoretical minimums in heat rates for prototype generation units.

Prototype technologies for California and non-California applications had different installed costs and emissions outputs. The installed cost for California units is provided in Table 6-9.

Table 6-9. Installed Cost of Various Generation Technologies – 2002 Dollars per Kilowatt

Technology	California Application	Non-California Application
Simple-Cycle Combustion Turbine	$550	$385
Combined-Cycle Combustion Turbine	$850	$650
Coal-fired Steam Plant	Not Applicable	$1600

Source: Ralph Zarumba prior work at Sargent and Lundy.

The installed cost reflects the overall higher costs associated with siting a unit in California, attaining stricter NOx emission standards and property costs. Coal-fired steam units were assumed to only be feasible in non-environmentally sensitive regions and thus excluded California.

All prototype generation was assumed to require a 14.5-percent IRR for the base case. This is about what is required to obtain a normal return levelized with investment bonds with a 50-50 cap structure. An alternative high cost of capital case was also run. In this scenario generating units constructed in California were assumed to require an IRR of 16.5 percent. The 2-percent premium for California plants is due to increased regulatory and financial risk.

6.5.3.6 Unit Retirements

Unit retirements for steam units were assumed to occur when a unit reaches 50 years of age. Simple cycle combustion turbines were assumed to have an economic life of 35 years. For the nuclear plants in the region, SAIC assumed these units would receive 20-year life extensions after the initial 40-year license expired. Hydroelectric units were assumed to not retire.

6.5.3.7 Emissions Allowances

California has very serious problems with the creation of ozone by NOx, and therefore is currently implementing every feasible control measure to reduce NOx emissions. Consequently, it is difficult to create voluntary surplus conditions of NOx emissions for use as offsets, because of stringent state and federal emission control requirements. For this reason, allowances in California are significantly more expensive than in the majority of the non-attainment regions of the United States. Also, ozone allowances in California are significantly more expensive than in the majority of the non-attainment regions in the United States. NOx allowances for California were priced at the equivalent of $10,740 per ton-year in 2002. After that time period it is assumed the price increased with inflation.

The balance of the WECC priced NOx allowances at $1,600 per ton. SOx allowances were priced at $303 per ton escalating at inflation.

6.5.3.8 Forced Outage Rates

Forced outage rates were adopted based upon NERC GADS data.[6] Forced outage rates were assigned based upon generating unit category.

6.5.3.9 Scheduled Outage Hours

Scheduled outage hours for each generating unit category used NERC GADS data.

6.5.3.10 Transmission Interconnections

Transmission interconnections were modeled using a transportation methodology, i.e., the capacity of transmission interconnections between regions was assumed not to vary within a given period. The transmission capabilities for the majority of the WECC were adopted from various WECC publications where non-simultaneous transmission was published. Detailed information about the SDG&E area was received from the Company and various CPUC filings.

6.5.3.11 Assumptions About Unspecified Generation Units

The Market Power model creates an optimal generation expansion plan based on the assumptions and parameters that were entered into the model. SAIC identified the following technologies as potential new generation additions in our analysis: A simple-cycle combustion turbine and combined cycle combustion turbine, which could be constructed in all areas except California. Simple- and combined-cycle combustion turbines, which could be constructed in California, are more expensive to build and operate because of higher construction costs and more stringent emissions standards.

6.5.3.12 Assumptions About Peak Demand

SDG&E's peak demand and energy usage forecast was adopted until 2006. After that time period from 2007–2020, the CEC forecast was used. After that time period, the growth rates were extrapolated. For the other California utilities, the CEC forecast was adopted. For non-California entities the Form 714 forecasts filed with the FERC were used.

[6] Source: http://www.nerc.com/~gads/

6.5.3.13 Forward Price Analysis

Forward price assumptions and analyses were estimated for four different cases representing different generation planning and expansion assumptions:

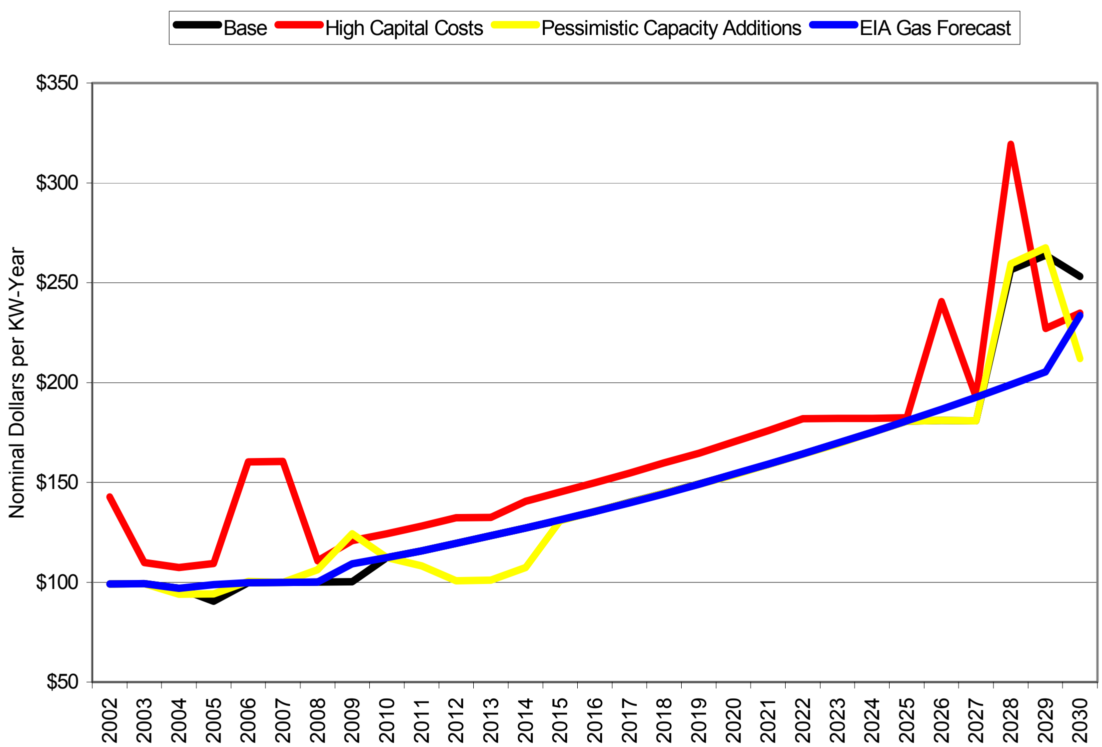
- Base Case Analysis: CEC gas price projections and standard assumptions for new generation and prototype new generation. This is the definitive forecast in California, with details specific to the west coast including delivered gas prices from San Juan Basin and local distribution fees.
- EIA Gas Forecast: SAIC used EIA projections of natural gas prices, and a lower forecast in generation based on a general equilibrium model for North America.
- Higher Capital Cost and IRR Analysis: Because a significant amount of new California generation is based upon political uncertainty. A higher IRR was used to capture fact that there may be of more risk in building plants in California. This is due to eminent domain, need to renegotiate contracts; delays in permit applications, etc.
- Pessimistic, Low Construction: Based upon a reduced level of construction in the 2002–2005 time period, the planned projects were cut 50 percent in the short-term and reduced projects in longer term by 75 percent in the WECC.

6.6 Results

6.6.1 Capacity Price Forecasts

Figure 6-4 presents a graph of the capacity prices that the Market Power model produced. Table 6-10 presents forward energy capacity values from 2002–2030.

Figure 6-4. Capacity Prices, 2002–2030



Note: Capacity prices are volatile in the post-2025 period due to some delay in plants being built and not all generating plants being identified in the later years to meet load growth. The forward prices in the later years are likely to be lowered due to new projects being identified in the late 2015–2020 and beyond time period.

Table 6-10. Forward Capacity Values ($/kW-yr)

Area	San Diego County							
Sum of Market	Year							
Key Assumptions	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Base	$99.14	$99.28	$96.98	$90.43	$99.77	$99.94	$100.11	$100.29
High Capital Costs	$142.79	$109.90	$107.30	$109.36	$160.26	$160.51	$110.71	$120.87
Pessimistic Capacity	$99.14	$99.28	$94.07	$94.22	$100.45	$99.94	$106.31	$124.27
EIA Gas Forecast	$99.14	$99.29	$96.98	$98.85	$99.77	$99.94	$100.11	$109.25
Key Assumptions	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Base	$112.37	$115.79	$119.53	$123.39	$127.19	$131.16	$135.48	$140.13
High Capital Costs	$124.33	$128.12	$132.27	$132.45	$140.60	$145.13	$149.80	$154.66
Pessimistic Capacity	$112.35	$108.11	$100.75	$101.03	$107.42	$130.72	$135.55	$139.95
EIA Gas Forecast	$112.37	$115.79	$119.53	$123.39	$127.20	$131.21	$135.45	$139.83
Key Assumptions	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Base	$144.62	$149.18	$154.03	$159.04	$164.24	$169.61	$175.10	$180.77
High Capital Costs	$159.73	$164.53	$170.32	$175.89	$181.90	$182.12	$182.35	$182.35
Pessimistic Capacity	$144.56	$149.03	$153.79	$159.02	$164.07	$169.24	$180.76	$180.76
EIA Gas Forecast	$144.33	$149.05	$154.14	$159.15	$164.30	$169.62	$180.78	$180.78
Key Assumptions	**2026**	**2027**	**2028**	**2029**	**2030**			
Base	$180.98	$180.87	$256.53	$263.86	$253.10			
High Capital Costs	$240.48	$192.59	$319.34	$227.05	$234.88			
Pessimistic Capacity	$180.95	$180.91	$259.41	$267.59	$212.02			
EIA Gas Forecast	$186.63	$192.68	$198.92	$205.36	$233.53			

NPV@15 Percent	**Base**	**High Capital**	**Pessimistic Scenario**	**EIA Gas Forecast**
2002–2006	$326.36	$420.02	$326.94	$331.17
2002–2011	$500.54	$637.56	$509.40	$508.29
2002–2016	$605.15	$752.52	$602.53	$612.91
2002–2021	$666.16	$819.90	$673.86	$673.86

6.6.2 Energy Price Forecasts

Figure 6-5 presents a forecast of the energy prices for 2002–2030. Table 6-11 presents energy forward price projections from 2002–2030.

Figure 6-5. Forward Energy Prices ($/MWh)

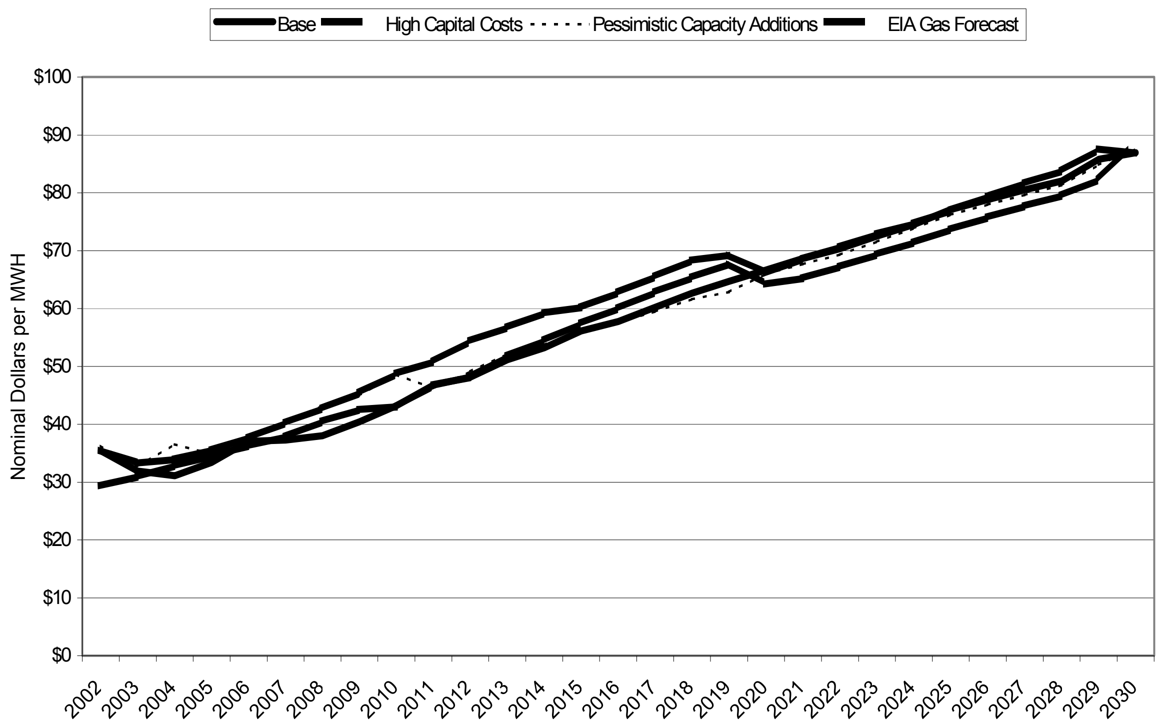


Table 6-11. Average Energy Price by Scenario ($/MWh)*

Average of Market Price		Year													
Scenario	Day Group	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Base	Weekday	36	32	31	34	37	38	38	41	44	47	49	52	54	57
	Weekend	35	31	30	33	36	36	37	39	42	45	47	49	51	54
High Capital Costs	Weekday	36	34	34	36	38	41	43	46	50	51	55	58	60	61
	Weekend	35	33	33	35	36	39	41	44	47	49	52	55	57	58
Pessimistic Capacity Additions	Weekday	37	33	37	35	38	41	44	46	49	47	50	53	55	57
	Weekend	36	32	36	34	36	39	41	43	46	44	47	49	51	53
EIA Gas Forecast	Weekday	29	31	33	35	37	38	41	43	43	47	49	53	55	58
	Weekend	29	31	32	34	35	37	39	41	42	45	47	50	53	55

Average of Market Price		Year														
Scenario	Day Group	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base	Weekday	59	61	64	66	68	70	72	74	76	79	81	83	84	88	89
	Weekend	55	57	59	61	63	65	66	68	70	72	73	75	76	80	82
High Capital Costs	Weekday	64	67	70	71	67	70	72	74	76	78	81	83	86	89	88
	Weekend	60	63	65	66	63	66	68	70	71	73	75	77	79	83	84
Pessimistic Capacity Additions	Weekday	59	61	63	64	68	69	71	73	76	78	80	82	83	87	89
	Weekend	54	56	58	59	62	63	65	67	69	72	73	75	76	80	83
EIA Gas Forecast	Weekday	61	64	67	69	65	66	68	71	73	75	77	79	81	84	91
	Weekend	57	60	62	64	62	62	64	66	68	70	72	74	75	78	85

*These prices are critical for valuing existing and new generation and also for developing avoided costs for screening demand-side programs. These prices were also used to screen and evaluate demand-side options in the project as well.

6.6.3 California Department of Water Resources (CDWR) Long-Term Power Contracts

The modeling completed for the WECC forward prices is based on the economic dispatch of combined cycle gas turbines and approximates the marginal cost of power in the WECC. The CDWR contracts are not expected to be the marginal resource at any time in the future. The CDWR is an active player in the wholesale market either purchasing or selling power. The CDWR contracts represent a limited proportion of the total power supply and the contract's time of termination varies.[7] The CDWR contracts do not create the market price over a 30-year period under investigation in this study. The marginal costs as driven by the forward prices were used to estimate the avoided costs for DSM and DG programs. Most analyses indicate that the CDWR contracts are above market cost. The premium of the contract prices over the market price should be treated as a stranded cost similar to the high-embedded costs of nuclear units in the 1980s.

The methodology employed to produce the wholesale price estimates used the most current assumptions available at the time the analysis was conducted. The objective was to produce estimates of the Long Run Marginal Cost (LRMC) for capacity and energy for the 30-year period of the analysis. The methodology used to produce these estimates is discussed below.

While forward prices presented in this report are somewhat lower than current DWR contracts, the result will be a slight underestimation of the economic attractiveness of DSM and renewables. However, in the post-2010 period, when DG and renewable resources are expected to gain significant ground, our prices are a realistic representation of the long run market value (LRMV).

6.6.4 California Financial Investment Climate and Cost of Building Plants in San Diego County

A major issue that will affect the cost and investment level of new power projects in San Diego and California is the current financial investment climate nationally and in particular, California, for power plant development. Enron's recent filing for bankruptcy and other energy marketer equity declines resulted in a 10-percent reduction in market capitalization (worth more than $4.2 billion) of the top 10 companies with exposure to Enron.[8] Five major companies have publicly announced capital budget cuts of more than $6 billion.[9] Because of this and other factors, California is facing great risk from current and proposed power development project delays and cancellations in the state. Unfortunately, the recent contract renegotiation with Calpine does not require that Otay Mesa plant be built (although it is strongly encouraged) by the end of 2004. Continued press reports on the state's energy problems plus the perceived regulatory climate in the state creates an image to the investment community that California is a high-risk environment for new power plants. For this reason, a higher rate-of-return was assumed in the SAIC Analysis. Generating plants built in Mexico and other areas of the WECC are less costly. These areas are likely to be considered first by developers before many newer plants will be built in the region.

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[7] According to SDG&E the CDWR contracts represent about 47% of the power for the region for at least the next 5 years. The CDWR contracts were not used as a basis of the analysis because they do not set wholesale power prices in the Western Power region—on the margin. The analysis used in this study assumed market-driven wholesale prices.

[8] Rich, Jim and Tange, Curtis, Potential Exposure: The Long View. *Public Utilities Fortnightly*. May 15, 2002, p. 42.

[9] *CERA North American Electric Power Watch*, Spring 2002.